FILED
10-05-07
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 06-03-005 (Dynamic Pricing Phase)

COMMENTS OF THE UTILITY REFORM NETWORK

ON DYNAMIC PRICING RATE DESIGN ISSUES

The Utility Reform Network
711 Van Ness Avenue, Suite 350
San Francisco, CA 94102
Phone: (415) 929-8876
Fax: (415) 929-1132
E-mail: mflorio@turn.org

October 5, 2007

Michel Peter Florio
Senior Attorney

COMMENTS OF TURN IN THE DYNAMIC PRICING PHASE

In accordance with the schedule established by the Assigned Commissioner's Ruling (ACR) of August 22, 2007 in this proceeding, The Utility Reform Network (TURN) respectfully submits these comments on the questions raised in the Rate Design section of the Issues List set forth in Attachment A to the ACR. TURN believes that the opportunity exists to develop some intriguing new rate options that have the potential to reduce overall system costs in a cost-effective manner and provide customers with enhanced opportunities to manage their electricity bills. At the same time, TURN submits that the Commission must take care to *carefully coordinate* its development of dynamic pricing policies with the wide variety of other energy initiatives currently underway in California. There is a serious risk of working at cross-purposes if policies related to energy efficiency, greenhouse gas (GHG) reduction, Resource Adequacy (RA) and wholesale market reform (to name just a few) are not given appropriate consideration in designing dynamic pricing tariffs and rate options.

TURN is especially concerned that this Commission not lose sight of its longstanding (30-plus year) commitment to conservation-oriented rate designs (including inverted tier rates for residential customers) as it moves forward into the new era of dynamic pricing. While reducing peak demand is clearly an important policy objective, this Commission has also assumed a prominent role not only nationally but internationally with its efforts to promote energy efficiency and GHG reduction. The success of those policies requires focus not only on peak demand but also on energy consumption throughout the day and year. In other words, appropriate rate design requires the ***balancing*** of a number of different policy goals. Pursuit of one to the exclusion of the others will not further the State's overall electricity policy objectives.

There is also a grave risk that the Commission's RA policies may operate at cross-purposes with the effort to implement meaningful dynamic pricing. In particular, the requirement that all Load Serving Entities (LSEs) procure sufficient capacity to provide a 15-17% Planning Reserve Margin (PRM) above forecasted monthly peak demand will likely suppress energy price volatility and drive spot market prices toward the marginal operating cost of the least efficient unit required to serve load, because the PRM assures that there will be a surplus of available energy almost all of the time. While such prices will still exhibit some degree of peak/off-peak differential, those differentials will likely be too small to stimulate very much demand response and peak load reduction most of the time. Thus, as the Commission considers its long-term RA policy in Phase 2 of R.05-12-013 and its dynamic pricing policies in this proceeding, it is essential that the crucial policy tradeoffs be well understood and thoroughly considered.

TURN is a member of the Bilateral Trading Group (BTG) that has proposed, in Phase 2 of R.05-12-013, a gradual transition toward an energy-based market structure, rather than one focused on a centralized market for capacity. An energy-based wholesale market structure with a well-developed scarcity pricing mechanism is highly compatible with a policy framework that relies on dynamic pricing at the retail level to moderate peak demands and maintain system reliability. On the other hand, a capacity-based system with high PRM requirements will suppress energy prices and eliminate much of the potential for demand to respond to changes in spot market energy prices. The demand side could still participate in such a market structure to some degree, but primarily through demand response *programs* that can be "counted" for RA purposes as the equivalent of a capacity resource. There will be little role or opportunity for *price responsive* demand in a market structure that depends on large fixed capacity commitments that must be procured in advance and that will only serve to suppress energy price volatility. Therefore, this Commission MUST exercise great care in order to assure that its Resource Adequacy and dynamic pricing policies are carefully coordinated, to avoid creating conflicting and incompatible incentives. This is clearly not a time in which various policy initiatives can each be considered in their own "silos" with little attention paid to what is occurring in the other silos. While coordination can be a daunting task with so many different initiatives being pursued simultaneously in different dockets, the risk of failure is great unless such coordination occurs.

This Commission should also give particular attention to the CAISO's efforts, consistent with the directives of the FERC, to implement reserve scarcity pricing within one year of the startup of MRTU. A well-developed scarcity pricing mechanism will allow wholesale spot prices to rise to very high levels under conditions of resource shortage (assuming that such shortages are allowed to occur at all). Scarcity pricing at the wholesale level is a good match for Critical Peak Pricing (CPP) at the retail level, and it may make sense to implement both policies simultaneously, or at minimum in close coordination.

I. Objectives of dynamic pricing and time-differentiated rates

1. What are the objectives of dynamic pricing and time-differentiated rates? How should the various objectives be prioritized? Some objectives, in no particular order of importance, are listed below:

• *Reflect marginal cost of electric service*. If the price faced by a consumer is close to the marginal cost of providing the electric service, the consumer can make efficient decisions and adjustments in usage patterns. Consumers may be able to lower their overall energy costs by reducing their electricity consumption during higher cost periods or shifting consumption from high cost to low cost periods.

• *Flatten the load curve.* The electric utility must make capital investments and contractual commitments to satisfy peak electric demand. Some of the generation, distribution, and transmission capacity is only needed during limited hours each year. Such investment may be avoided in the future if customers' rates are higher during peak hours and lower during off-peak hours, providing an incentive for customers to shift usage from peak to off-peak hours through changes in behavior and technology.

• *Reduce load in the face of short-term supply shortfall.* Unforeseen supply shortfalls can lead to involuntary curtailment of electric service to consumers. The probability of involuntary curtailment may not be reflected in the wholesale price. Tariffs that are specifically designed to reduce load in the face of supply shortfalls could help to avoid involuntary curtailment.

TURN agrees that all three of the stated objectives are important, but believes that "reducing load in the face of a short-term supply shortfall" is probably the most important, because the alternative may be rolling blackouts that are highly disruptive to customers and the economy as a whole. Flattening the load curve has the potential to reduce overall customer costs, but only as long as the measures employed to achieve that flattening are cost-effective.

Similarly, aligning rates with marginal costs can increase overall efficiency and likewise add to consumer welfare. This is far from a simple task, however. For example, if the Commission opts for a centralized capacity market structure for RA purposes, energy prices will likely reflect only the short-run marginal cost of running the existing fleet of generation. The long-run costs of adding new infrastructure would be reflected in capacity payments to generators that will not show up in market energy prices, and can only be incorporated into time-differentiated tariff rates through cumbersome and inexact allocation techniques. Thus, the Commission's decisions on market structure issues will have an impact on the marginal costs that are the basis for designing tariff rates.

Another important objective of dynamic pricing should be to provide customers with opportunities to manage their energy costs. By offering a menu of different rate options, the Commission can provide consumers with the tools most relevant to their particular circumstances and facilitate customers' own efforts to control their bills. Similarly, price responsive end-use demand can provide a powerful check on the potential exercise of market power by energy suppliers, and only a limited amount of demand response is typically needed to achieve this goal. These additional objectives deserve consideration along with the three explicitly mentioned in the ACR.

2. How should dynamic pricing policy be coordinated with other policy and rate design considerations such as energy efficiency, greenhouse gas emission reduction, rate stability, rate simplicity, cost causation, and utility cost recovery?

TURN strongly believes that the focus on dynamic pricing should not detract from or undermine this Commission's thirty-plus year commitment to rate designs that encourage conservation and energy efficiency. Rate design can promote both objectives so long as some degree of balance is maintained among the various goals. A myopic focus solely on peak load reduction may encourage increased usage at non-peak times and undermine the cost-effectiveness of the very same energy efficiency programs that this Commission had undertaken great efforts to promote. That would clearly be a grave and expensive mistake. Similarly, achievement of GHG reduction goals will require a focus on customer usage at all times of the year and not just during peak periods.

Rate design policy can also facilitate *both* energy efficiency and demand response by reducing the degree of reliance on demand charges and fixed customer charges and recovering more of the revenue requirement through energy charges. Customers can respond more effectively to energy price signals and tailor their consumption accordingly. It is worth asking the question of whether demand charges will eventually become obsolete in a world with ubiquitous interval metering.

Other policies that relate closely to the topics of this discussion include discouraging the use of electric stoves, which are less efficient than gas units and contribute to electric system peak demands.[1] Likewise, an increased focus on air conditioner efficiency will create benefits in terms of peak load reduction, increased efficiency and GHG reduction – the “three-for-one” benefit to the system.

Any discussion of rate design policy goals would be incomplete without mention of other longstanding criteria such as rate stability, rate simplicity, and customer acceptance. These factors will have a major impact on the success of any new rate design initiatives. For example, if rate structures are too complex, customers may become frustrated and not respond in the expected fashion. Large and unexpected increases in rates or bills can lead to customer dissatisfaction, and the resulting political fallout may scuttle promising experiments. This happened not long ago in the state of Washington, where Puget Sound Energy was forced to withdraw a mandatory residential TOU rate a year ahead of schedule because of adverse customer reaction (Seattle Post-Intelligence, November 15, 2002). Regardless of their potential theoretical merits, rate initiatives that

[1] While stoves do not contribute much to the “headline” system peak at 4pm, they are raising loads during the critical peak hours of 5-7 pm, thus imposing stress on the system on days with high loads. They also contribute to the later distribution system peaks in residential areas. Measured against the critical peak hours, stoves have a load factor of only about 25%.

fail the test of customer acceptance are unlikely to survive, let alone achieve their intended objectives. Thus, TURN believes that it will be important to advance new rate initiatives that provide real and useful opportunities for customers to manage their energy costs, and avoid those that simply punish customers with high rates, without offering a meaningful opportunity to respond.

II. Rate options

1. What rate options should be offered to each type of customer, including bundled, direct access, Community Choice Aggregation (CCA), and netmetering? Dynamic rates could include some or all of the following rate strategies:
- Peak, mid peak and off-peak period time-of-use (TOU) rates.
- TOU rates that have more time periods, such as hourly.
- Real time prices (RTP).
- Pre-defined high super peak rates during critical peak periods, or Critical Peak Prices (CPP).
- Rebates during critical peak periods.
- Any other?

Since direct access and CCA customers purchase their energy from a non-utility supplier, the utility is not in a position to offer dynamic prices to such customers, except to the limited extent that there is some time-differentiation reflected in transmission or distribution rates. Of course the non-utility suppliers may choose to offer dynamic rate options of their own to the customers that they serve.

TURN believes that for residential and small commercial (below 20 kW) customers it will be particularly important to keep the number of rate options to an understandable minimum, to avoid "information overload" and customer frustration. We suggest the offering of three basic utility rate options – the current class rate structure, a three-period summer/two-period winter TOU option (with a baseline overlay for residential) and a CPP option – in addition to existing demand response programs such as air conditioner (A/C) cycling. Anything more elaborate than this is likely to prove too confusing, at least for the next several years.[2]

It is important to recognize that the existing tiered "baseline" rate structure for residential customers provides a significant conservation and energy efficiency incentive in *all hours* of the year, *including* during peak periods. Only the smallest users, who almost by definition have the least potential to shift loads, are not exposed to the price signal of the upper tier rates. TURN continues to believe that this rate structure is appropriate as the default for residential class, whether or not it is required by law.

A TOU rate option could be made available to the residential class without running afoul of AB 1X or the baseline statutes. For example, time-differentiated prices could apply to ***usage in excess*** of the baseline quantity (or in excess of 130% of baseline during the AB 1X period), as long as the increasing block rate structure is maintained (*i.e.*, the off-peak rate for usage above the baseline quantity could not be less than the baseline rate). The above-baseline usage could be attributed to time periods in proportion to total usage by time period during the month. Alternatively, a TOU rate option could be structured to provide a baseline "credit" against the total bill, similar to the manner in which PG&E's optional residential TOU rates were designed historically.

An optional CPP rate structure could also be developed for the residential class (and other classes for that matter) via a linkage with Resource Adequacy policy. Today

[2] In addition, non-utility demand response aggregators may offer a greater variety of options to interested customers, but these would not be *utility* rate options.

all LSEs are required to procure a PRM of 15-17% above their forecasted monthly peak load, which effectively *fully hedges* their customers against supply shortages. This structure could be modified such that LSEs could procure to a lower PRM for those customers who opt for a CPP tariff – perhaps 10% but in any event no lower than the 7% required to maintain system *operating* reserves. The CPP customers would therefore pay a lower base rate than the fully hedged customers, reflecting the smaller amount of capacity that the LSE needs to procure in order to serve them. In exchange, the CPP customers would bear the risk of paying higher CPP/CAISO scarcity prices when such events occur.[3]

An advantage of this approach is that it does not impose any *higher* costs on the customers who do not opt for CPP, in recognition of the fact that such customers are already fully hedged as a result of RA compliance. The customers who choose CPP would obtain a lower rate, reflecting the cost savings from their lower PRM, for most hours of the year, but would be exposed to higher prices (but with the opportunity to avoid those higher costs through demand reductions) when the CPP events actually occur. TURN urges this Commission to consider this integrated dynamic pricing/ Resource Adequacy approach further as this proceeding advances.

2. Which tariffs should be voluntary, default with opt-out provisions, or mandatory?

TURN's comments here focus on residential and small commercial customers that we represent. For these relatively less sophisticated customers, TURN strongly

[3] A similarly reduced RA requirement would apply to ESPs or CCAs to the extent that their customers are subject to CPP rates similar to those offered by the IOUs.

recommends that any new tariffs be voluntary. Exposing these customers to mandatory or default tariffs with which they are not familiar is a recipe for adverse customer reaction and potentially even outrage. As early adopters sign up and report their experiences to their friends and neighbors, participation will grow naturally, just as has occurred historically with new technologies such as personal computers, cellular phones, and high-definition televisions. Attempting to force behavioral change too abruptly simply will not work in a mass market. If customer acceptance remains a rate design objective – as we believe it should -- allowing voluntary participation to grow over time is by far the better approach.

Over an extended period of time, it *may* be possible to transition to a default TOU rate structure for smaller customers (with a baseline overlay for residential), but any such decision should ***not*** be made now. Customers will naturally respond more positively to the provision of new options and choices that may benefit them, rather than to mandatory changes. Thus, educational efforts should focus on explaining the potential benefits of new rate options, not on rationalizing changes that are forced upon customers.

3. What are the advantages and disadvantages of rebates as an alternative to rates?

Rebates have the distinct advantage of providing a "carrot" rather than a "stick" to customers as a means of inducing behavioral change, and thus are likely to garner greater customer acceptance, even if the costs of the rebates are ultimately recovered from the same class of customers. On the other hand, a disadvantage of this approach is that it may reward a lot of free riders. Also, since customers would not sign up and be identified in advance, the utility would not know how many customers wish to be fully hedged against supply shortages and how many do not, as they would if customers volunteered to be on the CPP rate option described above.

4. Should automatic load control be considered as a substitute for dynamic pricing rates?

YES! TURN believes that automatic load control offers many of the same benefits as dynamic pricing, particularly for small customers, with less of the "hassle" factor from the customer's standpoint. These programs **should not be abandoned**, even when dynamic pricing becomes widely available. Automatic load control has real value to the system, because the CAISO operators can know with reasonable certainty how much load relief will be realized when the program is triggered. Also, load control programs can potentially be used to provide valuable ramping capability and ancillary services such as non-spinning reserves, which price-based demand response cannot provide. Automatic load control offers a meaningful choice for small customers, while avoiding the "information overload" problem that can occur with more complex rate options that require separate consumer decision-making for each event.[4]

While economists will always tend to prefer price-based incentives, the electrical system is not just a market but also a complex machine. Engineers, on the other hand, will generally prefer the certainty of "turning a knob" to obtain load reductions when needed and to provide ancillary services that must be known and quantifiable to assure

[4] With automatic load control, the customer choice is whether to sign up for the program, not a whole series of individual choices on an hour-by-hour basis.

system integrity. Since engineers actually run the system, their perspective must not be ignored.

5. Should customers be offered a large variety of rate options so that customers can find a rate option that works for them, or should customers be offered a small number of options to avoid confusion, simplify marketing and minimize administrative costs?

A large variety of options may work for the more sophisticated large customers, but for the residential and small commercial classes it is critical to avoid information overload. Too many options will confuse and frustrate many customers, making it all the more likely that they will decide to do nothing, rather than select among options that they do not fully understand. Demand response aggregators should also be allowed to market directly to selected customers, including residential, providing those who are more sophisticated and motivated with a wider range of options.

6. How should accuracy and simplicity be balanced in rate design?

TURN is not convinced that there is really any such thing as complete "accuracy" in rate design, since many judgments are involved in determining and allocating costs and reasonable experts can and typically do disagree. As discussed above, for large customers the balance should probably tilt toward providing more options, while for small customers simplicity and ease of understanding are more important.

Some parties may assert that RTP represents the ultimate of "accuracy" in rate design. However, in a market with RA requirements, the real-time price is likely to be suppressed and reflect only the *short-run* marginal cost of running the existing fleet of resources. Hence, it will not recover the full revenue requirement, which includes the capacity payments made to RA resources to remain available to the CAISO.

7. How should the expected ability of a customer group to respond to time-differentiated rates be taken into consideration?

The ability of customers to respond to the intended price signal is critical to customer acceptance of a rate design. If customers are hit with higher prices to which they are unable to respond, they will inevitably get angry, complain to their legislators, and possibly create a situation in which the Commission's authority is curtailed or overridden by statute. This is truly a situation where practicality should take precedence over theory. While it might be desirable in the abstract to expose all customers to real-time prices, the reality is that a little demand response will go a long way toward dealing with peak loads, resource shortages, and supplier market power. It may take a considerable period of time to change customer behavior, but the system does not need every single customer to be highly price responsive, even if those who reside in the ivory tower believe that they should be.

8. For customers that operate off-line and peaking generation facilities, how should the need to use system power for start-up operations be addressed?

TURN has no comment on this issue at this time.

9. What is the expected response of demand to rate options, taking into account results of pilot programs and relevant studies?

The expected response of residential demand to rate options should not be overstated. The results of the SPP pilot project showed energy savings in response to price that were far less than expected based on previous studies in the 1980s, as the latter showed roughly 70% greater response than in the SPP.[5] Furthermore, the residential SPP participants represented a subset of the population that was agreeable enough to the prospect of demand response that they acquiesced to be in the program for an incentive of $175. These results may therefore not be valid for populations that don't have these characteristics, e.g. opt-in and a sizeable incentive. Extending the SPP conclusions to the population at large, many of whom are not at all interested in demand response,[6] is particularly risky and likely to vastly overestimate potential demand response.

In particular, no doubt due to the meager energy savings predictable from the SPP results, utilities are considering other types of demand response programs for residential customers, such as opt out and peak time rebates. Great caution must be exercised in projecting demand response for these programs, however, as the SPP did not test these options. Even the results for TOU rates in the SPP are not reliable, as the sample sizes were small.[7]

10. Should customers be offered bill protection during an initial time period to learn how a rate might impact their bills?

Given the critical importance of customer acceptance, discussed above, TURN believes that an initial period of bill protection is essential to achieving a satisfactory response to the introduction of dramatically new tariff structures. Customers who may be

---

[5] Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot, March 16, 2005, p. 12.

[6] 70% rejected the opportunity to participate in a "no lose" demand response program in Anaheim. Marcus, Nahigian, and Schilberg for UCAN, Analysis of SDG&E's Advanced Metering Infrastructure Application, August 14, 2006, A. 05-03-015, p. 61. Four out of every five customers who were contacted did not choose to participate in the SPP, even for a $175 incentive (p. 66).

[7] CRA, ibid., p. 8.

interested in participating in a new rate offering will be much more willing to "take the chance" if they have an opportunity to "test drive" the new option before committing to it. On other hand, customers are likely to react negatively if they are recruited (let alone forced) into a new tariff and end up being worse off as a result.

11. How would offering bill protection affect customers' response to dynamic pricing tariffs?

There is no factual basis for predicting what the short-run impacts of bill protection might be, but the short-run is not what is really important here. In the long run a program is more likely to be successful if customers are happy with it, and they are more likely to be happy if they have the opportunity for a no-risk trial run.

12. What are the potential distributional impacts of dynamic pricing rates?

This is a factual question for which there is no clear answer. TURN has expressed its concern in the past that for small users, including many low-income customers, the cost of the metering equipment necessary to enable dynamic pricing is too large to be overcome by any feasible potential bill savings. Now that AMI is essentially a sunk cost, however, the "disbenefits" of that action for the smaller residential users may be offset to some degree by the fact that such customers tend to have flatter load profiles than larger residential customers. However, even if the average low-income customer might benefit structurally from dynamic pricing (by using less energy than the average, such that their baseload refrigerator is a larger percentage of their load), there are many customers who will not benefit – particularly those living in hot climate zones. Disadvantages to such customers must be taken very seriously.

III. Components of dynamic pricing tariffs

1. Which utility costs vary over time, vary with volume delivered, vary with demand, and/or are fixed? Which utility costs are fixed in the short run, but vary in the long-run?

This is a factual issue that tends to be disputed at least to some degree in virtually every cost allocation and rate design proceeding. At one end of the continuum, energy and ancillary services costs clearly vary over time and by the volume consumed, and with the implementation of MRTU, such costs will also vary locationally to some unknown extent. Externality costs such as GHG impacts, which are not yet priced, also vary by time and by the volume of power consumed. Certain costs of providing local area reliability also vary by time and location. Transmission and distribution costs vary to some extent with the level of demand, but such effects are usually very localized. Infrastructure costs tend to be fixed in the short run but are variable over some longer-term time horizon. It should be noted that CPP may not reduce distribution costs in residential areas, because residential demand tends to peak later in the day than the system as a whole unless the CPP timing is extended until 7 or 8 pm (which may generate customer acceptance issues). Also, the fact that certain costs may be fixed in nature does not necessarily imply that they should be collected through fixed charges, since charges that vary with usage have a much greater impact in achieving energy efficiency and GHG reduction goals than fixed charges.

2. What costs should be recovered through the time-variant portion of the rate?

This is also primarily a factual question upon which experts can and do disagree. Generally speaking, generation-related costs, including ancillary services and local reliability costs, are the best candidates for time-varying charges. Some transmission and a portion of distribution costs may also be appropriate for time-varying charges, but such costs should not be recovered in CPP rates, because system-wide peaks are not necessarily the drivers of such costs.

3. How should time variant costs be determined?

This is an even more factually intensive question for which evidentiary hearings would be appropriate.

4. What is the appropriate time granularity for measuring electric service costs in connection with dynamic rate design—annual, monthly, weekly, daily, hourly, ten minutes, etc.?

This is again a highly factual question. TURN would generally recommend measuring generation-related costs by TOU period, with a CPP overlay for scarcity-related shortage costs, although large customers should be able to opt for hourly price granularity if they so choose. Transmission and distribution costs generally are not visible on a granular basis.

5. How closely should the time profile of dynamic rates be aligned with the time profile of service costs?

Such alignment will be difficult, even for generation-related costs, because RA requirements tend to suppress the variability of energy costs. Other costs such as T&D are somewhat peak-oriented but it is difficult to determine to what degree.

6. If a time variant rate requires market price information, will the rate require information from the California Independent System Operator's (CAISO) Market Redesign and Technology Update (MRTU)?

Yes.

7. Should some costs be recovered through a flat customer charge,
demand charge, and/or non-varying per kW-hour charge?

This is another question that should be the subject of expert testimony. For residential customers, TURN believes that a tiered volumetric rate, with no demand or customer charges, is desirable to promote energy efficiency and GHG reduction. Fixed charges should also be minimized for the small commercial class. For larger customers, AMI may allow most costs to be recovered through time-varying volumetric rates rather than through demand charges.

8. Should the components of the rate that are collecting fixed costs vary
over time? If so, how should fixed costs be allocated to different time periods?

This is yet another fact-based inquiry. Generally speaking, some T&D costs are appropriately more heavily weighted toward peak periods, but the costs of the major interties are more driven by the need for access to cheaper energy and less impacted by peak demand factors.

9. How should the costs for public purpose programs and other nonbypassable
charges be reflected in the time-variant portion of rates, if at all?

Such costs do not really vary by time of use and should be recovered through non-time variant energy charges for simplicity and to provide greater assurance of timely revenue recovery.

10. What balance between fixed and time-variant costs will achieve the
objectives of the tariffs?

This is the type of question that would best be addressed through expert testimony in a ratesetting proceeding. Also, fixed and time variant charges are not only options, as non-time variant usage charges and tiered rates are also valuable rate design tools.

11. Should direct access and CCA customers be able to participate in time variant rates?

This is an issue between the customers and their suppliers, and largely beyond the Commission's jurisdiction, except to the extent that there are modest time variations in T&D rates.

12. If a rate is intended to reduce load in the face of a short-term supply shortfall, should the design of the rate differ depending on whether the shortfall is forecast on a day-ahead or day-of basis?

Small customers are unlikely to be able to respond to same day price signals, except through automated systems such as A/C cycling or other automated load controls. It is a matter of common sense that with current technology, customers who are already at work cannot return home to shut off their home air conditioners just because the price has gone up in real time, in spite of the previous day's expectation that a high price would not occur. An additional advantage of such directly controlled loads is that they can be bid into the CAISO markets for Residual Unit Commitment (RUC) and real-time dispatch.

IV. Recovering the revenue requirement

1. How can rates be designed to both recover the revenue requirement and communicate price information?

Decoupling and revenue balancing accounts can assure ultimate recovery of the revenue requirement regardless of the time-varying nature of prices.

2. How can rates be designed to avoid large periodic rate adjustments to recover revenues?

This question is probably premature at this time. It is very difficult to predict at this point how large any potential over- or undercollections might be.

3. Does the utility need to be able to forecast accurately the response of customers to these differential rates?

Better forecasting is always desirable, but revenue balancing accounts ensure that authorized revenue requirements will ultimately be recovered. The utilities already forecast TOU revenues by time period and residential revenues by rate tier.

4. Do the utilities need reliable estimates of price elasticities of demand for customers to make sales projections?

Same answer as #3 above.

5. What estimates of price elasticities exist and can be relied upon for rate design purposes?

TURN will review the utilities' responses to this question and may provide comments in its reply.

6. If customer responses to dynamic pricing tariffs result in revenue over- or under-collections, should the over- or under-collection be addressed by adjusting rates within the customer's class, or should the over- or undercollection be addressed by adjusting rates for all customer classes?

Consistent with current practice, such over- or undercollections should be recovered within the same customer class. Otherwise representatives of each customer class would have to participate in the rate design process for every other class, which would vastly complicate such proceedings.

7. If customers' self-selection into voluntary dynamic pricing tariffs results in over- or under-collections, how should the over- or under-collection be recovered—by adjusting rates of customers taking service under the voluntary tariff, by adjusting the rates of all customers within the customers' class, or by adjusting rates for all customers?

This is a question that may benefit from some real experience, and is difficult to answer *a priori*. The costs should definitely stay within the customer class, but beyond that the situation will require close monitoring, because as customers move from one tariff to another they change the composition of the customer group on each tariff, which can create perverse effects, as occurred on the PG&E system with the introduction of the E-7 residential tariff and customer migration over time.

8. What mechanisms should the utility use to recover over- and undercollections from customers?

The existing revenue balancing accounts generally serve this function, but with the introduction of more rate options, it may be necessary to create sub-accounts to track certain revenue variations by customer class as well as in the aggregate.

9. Should dynamic pricing tariffs be revenue-neutral with respect to flat and less time differentiated tariffs, or should the revenues collected by dynamic pricing tariffs differ from the revenues collected by flat and less time differentiated tariffs due to the incorporation of hedging premiums or participation credits?

Under TURN's proposal to integrate dynamic pricing with Resource Adequacy, described above, the customers taking service under the CPP tariff would pay lower base rates due to the lower reserve margins assigned to them, but would be subject to potentially higher costs when CPP events are called. This is a cost-based rate differential, but one that would not require rate increases for existing customers..

10. If the incorporation of hedging premiums or participation credits results a revenue over- or under-collection, how should the revenue over- or under- collection be treated?

At least initially, such over- or undercollections should be allocated to all customers in the class. Over time, it may be necessary to implement a more detailed accounting of the sources of such revenue differences, but doing so seems premature at this time until more experience is gained.

11. If the average cost to serve customers on a particular dynamic pricing tariff is less than the cost to serve customers not on the tariff, can the tariff be structured so that the dynamic pricing customers have a lower average cost?

At the outset TURN recommends that the only cost differential be that resulting from the lower reserve margin for CPP customers. We are reluctant to further "balkanize" the customer classes, because such differentiation can create unintended consequences, as in the PG&E E-7 example, when the apparent cost differences have nothing to do with the tariff itself. In other words, allowing such average cost differences will tend to create more "structural winners" as a result of the offering of the new tariff.

12. If the utility incurs incremental costs to implement dynamic pricing tariffs (e.g. administrative costs, equipment, education), how should the incremental costs be recovered?

TURN would recommend that such costs be allocated to all customer classes on the basis of generation EPMC, since the purpose of the tariffs is to reduce the generation costs that would otherwise be incurred. Keeping such costs within the specific customer class increases the potential for creating structural losers simply because of the costs of implementing the new tariffs.

V. Hedging

1. Should customers have the opportunity to hedge the price risk under some or all of the dynamic tariff options?

Customers should have the option to remain on their current tariffs, which are already very well hedged due to resource adequacy and other procurement policies. The dynamic pricing tariff options should be designed for customers who desire *less* hedging.

2. Should hedging options be offered by the utility, or should rates be structured so that hedging can be obtained externally in the marketplace?

Utility portfolios are already very well hedged. That should remain the policy, at least for small customers. TURN does not understand the rationale for forcing customers to obtain hedging externally in the marketplace.

3. If a hedging premium is incorporated into relatively flatter rates, what should the premium be and how should it be determined?

As explained above, current rates already reflect a hedging premium. Customers who select the CPP option would pay a lower base rate to reflect the reduced hedging that will be undertaken on their behalf.

4. Should customers have the opportunity to hedge through a two-part tariff in which part of their consumption is purchased at a fixed rate and the rest is purchased at the dynamic rate?

Such an option may make sense for larger customers, but is too complex to make sense for residential and small commercial customers.

VI. Sources of triggers and prices for dynamic prices

1. For trigger-based rates such as CPP, who should determine when an event is triggered—the CAISO or the utility?

Under TURN's proposal, the CPP rate would be triggered by the CAISO's activation of reserve scarcity pricing. However, at least for small customers, this option is only viable if the triggering occurs day-ahead. If the IOU is the one that determines the trigger, the associated load should be bid into the CAISO market day-ahead, so that the CAISO knows that the load reduction is there at some price.

2. Should RTP be linked to wholesale market prices or some other price or cost information?

RTP should be linked to wholesale market prices, however, this option is not really a viable one for small customers.

3. If a RTP rate is linked to wholesale market prices, what wholesale market prices should the tariff be linked to?

TURN believes that customers of any size would be better equipped to respond to day-ahead prices. However, we would not object if some customers wanted to pay real-time rather than day-ahead prices.

4. What impact will MRTU and potential capacity market implementation have on the prices used to design RTP and other dynamic tariffs?

Generally speaking, implementation of MRTU is at least a desirable, and probably a necessary, precondition to reasonable adoption of dynamic pricing, since the current ISO real-time market is only a balancing market that does not provide consistent and sensible price signals. Scarcity pricing will not be implemented until one year after the start of MRTU, and is probably a precondition to effective introduction of CPP, although some proxy might be employed for an initial "test run."

Implementation of a centralized capacity market would suppress CAISO market prices, and may very well render dynamic pricing effectively useless due to the muted energy price signals. Indeed, CAISO staff has stated that scarcity pricing is unlikely to be triggered very often, if at all, under the current RA regime. This is one of the major reasons why the Bilateral Trading Group has advocated a transition to an energy-based, rather than capacity-based, market structure. Price responsive demand is very unlikely to develop under a system with mandatory high reserve margins, because energy prices will be driven down toward short-run marginal operating costs. TURN's proposal to integrate dynamic pricing with RA through a lower required PRM for CPP customers offers a way to counteract the price suppressing effects of a capacity-based regime.

5. Will the variation in wholesale market prices impact customer behavior?

The answer depends in the first instance on the structure of retail rates. Assuming that wholesale prices are visible to at least some retail customers, the degree of variation in those prices will determine how much impact there is on customer behavior. If energy prices reflect only short-run marginal operating costs, there is unlikely to be much impact on customer behavior beyond what occurs under TOU rates today. On the other hand, if wholesale prices rise to reflect relative scarcity, customer price response is much more likely to occur.

In any event, TURN believes that most small customers are more likely to modify their usage through automated demand response, rather than behavioral changes in response to varying market prices. Hourly prices are likely to present a "too much information" problem for the vast majority of small customers.

6. Should tariffs be tied to the day-ahead or the same-day real time price?

TURN believes that small customers are unlikely to be able to respond effectively to real-time events and prices, except via automation. We suspect the same may be true for many large customers, but will leave it to them to explain their circumstances.

7. How should the real time price be communicated to customers?

TURN has no comment on this issue at this time.

8. Should the RTP rate be a two-part rate with both a fixed price portion for part a customer's usage and a dynamic portion for the remaining usage?

No comment at this time.

9. Under a two-part RTP rate, how should a customer's reference level for the fixed portion be determined?

No comment.

10. Under a two-part RTP rate, what costs should be recovered in the fixed portion of the rate?

No comment.

VII. Residential rate issues

1. What dynamic rates should be offered to residential customers while the rate protection offered under AB 1X remains in effect?

As discussed above, TURN believes that both TOU and CPP rates can be offered to residential customers consistent with AB 1X, so long as such rates are optional.

2. What types of dynamic rates can be offered to residential customers if the AB 1X rate protection is lifted by the Legislature or is no longer effective?

Even in the absence of AB 1X, state law still requires a baseline rate system with an increasing block rate structure for residential customers, as provided in Public Utilities Code Sections 739(c)(1) and 739.7. Thus, TURN's answer here is largely the same as to Question 1, above.

3. How can rates be designed to maximize residential participation while the AB 1X rate protection remains in effect?

Residential customers will participate in a dynamic rate program if they perceive that there will be benefits to such participation that exceed the "hassle factor" of learning to deal with a different rate paradigm. Some early adopters may be inclined to seize this opportunity, but most customers will probably be content to remain on their current tariffs until the benefits of an alternative are demonstrated to them. This will take time.

4. To what extent do existing residential rates and programs such as increasing block rates and air conditioning cycling fulfill the Commission's policy goals?

TURN believes that that increasing block rates and A/C cycling fulfill the Commission's policy goals quite well, at least as far as we understand those goals. Increasing block rates provide a strong incentive for conservation, energy efficiency, GHG reduction, solar installation, etc., for all but the smallest customers who have the least load to shift and the smallest potential savings. A/C cycling programs provide assured load reductions to the CAISO when called upon, and are thus a highly reliable resource that can be counted upon more firmly than price-based responses, at least for now. As technological developments permit, TURN envisions greater residential customer participation in automated load control programs, with both price and/or reliability-based triggers.

5. Could additional demand response could be provided if AB 1X rate protection were no longer effective? If so, how much additional demand response? What would the potential bill impact be for residential customers if they were able to participate in dynamic pricing rates?

Given the existence of the longstanding baseline rate statutes cited above, TURN does not believe removal of the AB 1X rate protections alone would make much difference in terms of the basic residential rate structure, although the levels and numbers of rate tiers certainly might change. TURN does not believe that anyone can reasonably claim to know how much residential demand response might result from a different rate structure, and requests the right to cross-examine anyone who makes such a claim. The potential bill impacts of dynamic pricing are heavily dependent upon the particular form of pricing that might be adopted, but residential customers would still be able to *voluntarily* participate in dynamic pricing even without any statutory changes.

6. How would existing residential rates and programs such as increasing block rates and air conditioning cycling be affected by dynamic pricing rates for residential customers?

TURN is concerned that if dynamic pricing is made available to residential customers, the utilities might be inclined to abandon their highly reliable, cost-effective and successful direct load control programs. That would be a very bad idea, since these programs have provided a valuable resource to the State for a number of years. The better approach would be to augment the existing programs with additional options, including potentially a price trigger for direct load control.

TOU rates could be adopted as an overlay to the existing residential rate design for usage above 130% of baseline, and usage over the baseline quantity once AB 1X expires.

7. Should low-income residential customers be offered discounted dynamic rates or other dynamic rate options?

TURN does not support the offering of a CPP-type rate to low-income customers.

On average, CARE customers use less energy than non-CARE customers and have a flatter load profile, meaning that they are likely to have fewer controllable loads, if only for the common-sense reason that the refrigerator is a larger portion of the load of a small customer than of a larger customer.   Therefore, leaving CARE customers out of the program will not have a large impact on load reduction.

However, there are significant exceptions to this general observation, particularly among customers in hotter climate zones living in poorly insulated dwellings, and the Commission's policy must be designed to prevent serious harm to those customers. Many subcomponents of the low-income customer group are likely to be ill-informed about CPP (non-English speakers, the elderly, and people without access to or ability to use a computer) and could easily face hardship if forced into a CPP rate without adequate information. They could face unaffordable bills and disconnection of service. Alternatively, there is a significant danger that such customers may be forced into life-threatening reductions in usage when CPP events are triggered. PEOPLE COULD DIE!

Other types of rates that do not incorporate the extremes of CPP pricing might be offered on a equivalent discount basis to CARE customers, however.

VIII. Critical Peak Pricing

1. What should a CPP rate be based on? Is there a reliability value that is not included in wholesale power prices that should be incorporated into the tariff?

The most logical basis for a CPP rate would be the scarcity prices adopted by the CAISO to apply during reserve shortage conditions. Such prices would incorporate the reliability value that is not otherwise included in wholesale market prices.

2. How long should the critical peak period be?

The critical peak period should not exceed six hours, but could be shorter if appropriate. There is a serious potential for "snap back" or erosion of the load reductions achieved earlier in the critical peak period if the duration extends for too long. This could result in loads coming back onto the system before the worst hours of the day have passed. For example, when a customer turns up his/her thermostat, whether voluntarily or using a device such as a programmable thermostat, load might be shed in the early afternoon but by late afternoon temperatures may have risen enough that the A/C comes back on even at the higher setting. The whole potential for such erosion of load reductions over time needs to be further analyzed.

3. When should a utility be able to trigger a critical peak period—during summer peak hours only, during summer mid-peak and off-peak hours, during winter hours?

CPP events should be triggered when required, which may be on summer weekends or at other times of the year when there are major plant or transmission line outages. However, too many events at unexpected times may threaten customer acceptance, so that events outside of weekday afternoons should be minimized if possible.

4. How can a CPP tariff be structured to allow for a variable number of events each year while still recovering the revenue requirement?

Existing revenue balancing accounts can address this problem.

5. Is the potential customer savings or cost great enough under a CPP rate to motivate a customer response?

No. TURN's analysis of both the PG&E- and SDG&E-proposed demand response programs to accompany AMI showed that bill savings are very small and unlikely to sustain long term participation for financial reasons.

Generally speaking, the smaller the customer the less likely it is that the potential savings will be great enough to motivate a response. Even for large residential customers with air conditioning it is doubtful that bill savings of less than $5 per month would motivate continued efforts to save peak energy. In the case of PG&E,[8] TURN found that 44% of the A/C customers in the target climate zones (PG&E's Mountain/Desert and Valley) would experience bill increases or savings of less than $5/month under PG&E's proposed CPP program, despite saving 21% of their peak energy. We therefore would not expect almost half of the targeted A/C customers to participate in the long run, due to minimal or negative bill savings. It is important for the Commission to recognize that

---

[8] Testimony of Nahigian, Schilberg, and Marcus in A.05-06-028, p. 54-55.

because of the complexities of rates and usage, a reduction in peak energy does NOT necessarily result in a lower bill.

For the program proposed by SDG&E, the expected bill savings were also quite small, a maximum of $1-$3/month, and unlikely to sustain long-run participation.[9] Evidence showed that customers mainly participate in demand response in order to save money, expecting on the order of 10-25% bill savings.[10] The SPP also showed that customers preferred the option to do nothing (make no energy adjustments) for only 10% or 20% bill savings.[11] A SMUD study considered that customers would "benefit" if they could save at least $50 during 90 critical peak hours.[12] Since bill savings of this magnitude are not available to most customers under proposed CPP-type programs, we expect that long run participation in such programs will only come from customers whose motivation is not financial but rather who desire to conserve electricity or learn to manage electrical use.[13]

The theory upon which the hope of demand response is based, that customers will respond to price signals, has little power for the small bill savings that are possible with these programs and the large efforts that will be required to achieve significant energy savings.

---

[9] Marcus, Nahigian, and Schilberg for UCAN, ibid., p. 70-72.

[10] Ibid, p. 74, quoting SDG&E's focus group study. "Six percent is nothing, not worth the stress of running around changing things."

[11] Ibid, p. 75, quoting the Momentum "Customer Preferences Market Research, Residential," December 2003, p.78.

[12] Ibid, p. 77.

[13] Ibid, p. 79. For 26% of SPP participants the most important reason was not financial. Momentum, "SPP End of Summer Survey," February 2004, p. 63.

IX. Relationship to reliability-oriented and other demand response programs

In addition to responding to the Commission's specific questions, we first provide information on one other topic that is reliability-oriented and which the Commission needs to understand. Traditionally, at times of high peak loads, there are public appeals for conservation ("Flex Your Power", *etc.*). While not a "program" per se, these appeals have often been successful in reducing demand on hot summer afternoons by hundreds of megawatts or more. The Commission and CAISO need to be mindful that demand response programs overlap with the load reduction resulting from public appeals. Many of the customers who respond to public appeals will instead be participants in CPP or other price-based demand response programs. Because of the overlap, there is likely to be less conservation resulting from public appeals once demand response programs are put in place, which may require the ISO to change its forecasting methods and its system operations.

1. What is the purpose of reliability-oriented demand response tariffs and programs such as interruptible rates and programs and air conditioning cycling?

Generally speaking, the purpose of such programs has been to shed in a controlled manner the loads of customers who have agreed to accept such interruption in return for an incentive payment in some form, thus avoiding the need for involuntary load reductions or other system problems.

2. To what extent can dynamic pricing rates provide the reliability benefits that are provided by reliability-oriented tariffs and programs?

Price-based approaches are unlikely to provide the reliability benefits of the current programs, particularly in the near term, because the resulting load reductions are less predictable and assured. The CAISO has considerable confidence in the performance of interruptible and A/C cycling programs, but is unlikely to place the same reliance on price-based programs unless and until a track record of performance is established. For example, load reductions from programmable thermostats (whether called on a price or reliability basis) occur in a different pattern than A/C cycling, and may result in a snap-back of load before the critical period has passed. This phenomenon has yet to be studied.

3. Should customers have the option to simultaneously participate in dynamic pricing tariffs and interruptible or other reliability programs?

Simultaneous participation should only be allowed under conditions that preclude double payment for the same load reduction. Under current tariffs, reliability-based programs are typically called only in a Stage 2 emergency, while scarcity pricing/CPP is likely to be invoked sooner and more frequently, whenever there is a reserve shortage of any magnitude. If the triggers for both types of programs are eventually synchronized, it may not make sense to allow simultaneous participation.

4. When simultaneous participation is allowed, what rules are needed to minimize overpaying customers for demand reductions?

The answer depends upon the specifics of the particular programs involved.

5. Should customers have the option to simultaneously participate in dynamic pricing tariffs and other price-responsive programs?

Potentially, again so long as there is no double payment.

X. Timing of tariff development and roll-out

1. When should time-differentiated tariffs be introduced for each customer class?

TOU rates can be implemented now, to the extent that the metering is in place, and already exist for many larger customers. RTP is probably dependent upon the availability of prices from MRTU, as well as appropriate metering. CPP would work best in conjunction with CAISO scarcity pricing but could potentially be implemented prior to that based on the use of some proxy, again assuming adequate metering.

2. Does the detailed development of some time-differentiated tariffs need to wait until after the CAISO's MRTU is on-line?

Yes, at least for RTP and perhaps for CPP as well.

3. How does the meter installation schedule for small commercial and residential customers affect when tariffs should be introduced?

It will be difficult if not impossible to implement dynamic pricing until appropriate metering is in place.

4. Should customers be given time before the implementation of new time-differentiated tariffs so that customers may make technological and operational changes to benefit from the new tariffs?

Such time should certainly be provided if customers are going to be placed on new tariffs other than voluntarily. If the tariffs are voluntary, they could be implemented and customers could switch over when they are ready. It would also be desirable to provide bill protection for customers for a reasonable period of time while they gain familiarity with the new tariffs.

TURN appreciates the opportunity to offer these comments to the Commission.

Respectfully submitted,

THE UTILITY REFORM NETWORK

October 5, 2007

By: ____________/S/_______________

Michel Peter Florio
Senior Attorney

CERTIFICATE OF SERVICE

I, Larry Wong, certify under penalty of perjury under the laws of the State of California that the following is true and correct:

On October 5, 2007 I served the attached:

COMMENTS OF THE UTILITY REFORM NETWORK

ON DYNAMIC PRICING RATE DESIGN ISSUES

on all eligible parties on the attached lists to **A.06-03-005**, by sending said document by electronic mail to each of the parties via electronic mail, as reflected on the attached Service List.

Executed this October 5, 2007, at San Francisco, California.

/S/

Larry Wong

Service List for A.06-03-005

act6@pge.com
ahk4@pge.com
ahmad.faruqui@brattle.com
atrowbridge@daycartermurphy.com
bill@econsci.com
bill@jbsenergy.com
blaising@braunlegal.com
brbarkovich@earthlink.net
bruce.foster@sce.com
Case.Admin@sce.com
casner@packetdesign.com
cbaaqee@ebmud.com
cem@newsdata.com
CentralFiles@semprautilities.com
chrism@mid.org
CManson@semprautilities.com
cmkehrein@ems-ca.com
dbyers@landuselaw.com
dcarroll@downeybrand.com
dfc2@pge.com
dgeis@dolphingroup.org
douglass@energyattorney.com
dss8@pge.com
ek@a-klaw.com
epoole@adplaw.com
filings@a-klaw.com
francis.mcnulty@sce.com
gayatri@jbsenergy.com
glw@eslawfirm.com
gtropsa@ice-energy.com
hayley@turn.org
info@calseia.org
jeanne.sole@sfgov.org
Jennifer.Shigekawa@sce.com
jimross@r-c-s-inc.com
joyw@mid.org
jpross@sungevity.com
jsqueri@gmssr.com
jwiedman@goodinmacbride.com
karen@klindh.com
KCordova@semprautilities.com
keith.mccrea@sablaw.com
kfoley@sempra.com
khojasteh.davoodi@navy.mil
kjsimonsen@ems-ca.com
klatt@energyattorney.com
laura.rooke@pgn.com
liddell@energyattorney.com
lmh@eslawfirm.com
lnelson@westernrenewables.com

agc@cpuc.ca.gov
bkb@cpuc.ca.gov
bsk@cpuc.ca.gov
bsl@cpuc.ca.gov
crv@cpuc.ca.gov
dkf@cpuc.ca.gov
dlf@cpuc.ca.gov
fvr@cpuc.ca.gov
gxh@cpuc.ca.gov
jef@cpuc.ca.gov
nil@cpuc.ca.gov
pfa@cpuc.ca.gov
shn@cpuc.ca.gov
wtr@cpuc.ca.gov

lrn3@pge.com
marcel@turn.org
maricruz.prado@sce.com
mark.s.martinez@sce.com
mbrubaker@consultbai.com
mday@goodinmacbride.com
mrw@mrwassoc.com
nes@a-klaw.com
norman.furuta@navy.mil
phanschen@mofo.com
pk@utilitycostmanagement.com
pthompson@summitblue.com
ralph.dennis@constellation.com
rat9@pge.com
rkeen@manatt.com
rliebert@cfbf.com
rmccann@umich.edu
rob@clfp.com
rogerl47@aol.com
rosshemphill@fscgroup.com
rrh3@pge.com
rschmidt@bartlewells.com
russell.worden@sce.com
rwethera@energy.state.ca.us
SAW0@pge.com
sdbraithwait@caenergy.com
sls@a-klaw.com
smindel@knowledgeinenergy.com
stacie.schaffer@sce.com
stephen.morrison@sfgov.org
stephengeorge@fscgroup.com
tburke@sfwater.org
tmacbride@goodinmacbride.com
tomb@crossborderenergy.com
wbooth@booth-law.com
wendy@econinsights.com